IN THE MATTER OF THE PROVISION OF BASIC GENERATION SERVICE FOR BASIC GENERATION SERVICE REQUIREMENTS EFFECTIVE JUNE 1, 2022	:	Docket No. ER21030631

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

PROPOSAL FOR

BASIC GENERATION SERVICE REQUIREMENTS

TO BE PROCURED EFFECTIVE JUNE 1, 2022

COMPANY SPECIFIC ADDENDUM

July 1, 2021

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I. USE OF COMMITTED SUPPLY AND CONTINGENCY PLANS

COMMITTED SUPPLY

"Committed Supply," means non-utility generation power supplies to which Public Service Electric and Gas ("PSE&G" or "Public Service" or "Company") has an existing physical or financial entitlement. In prior auctions, PSE&G provided renewable attributes from non-utility generation contracts on a pro-rata basis to BGS-RSCP Suppliers. Since PSE&G's last non-utility generation contract was terminated in 2014, no renewable attributes will be available going forward. PSE&G has no committed supply.

CONTINGENCY PLANS

While not every contingency can be anticipated, we can differentiate three time periods of concern:

(a) There are an insufficient number of bids to provide for a fully subscribed Auction Volume either for the BGS-RSCP auction or the BGS-CIEP auction;

(b) A default by one of the winning bidders prior to June 1, 2022;

(c) A default during the June 1, 2022 – May 31, 2025 supply period.

(a) Insufficient Number of Bids in Auction

In order to ensure that the Auction Process achieves the best price for customers, the degree of competition in the auction must be sufficient. To ensure a sufficient degree of competition, the target volume of BGS-RSCP and BGS-CIEP Load purchased at each auction will be decided after the first round bids are received. Provided that there are sufficient bids at the starting prices, the auctions will be held for 100 percent of BGS-RSCP and BGS-CIEP Load.

It is possible that the amount of initial bids will not result in a competitive auction for 100 percent of the BGS-RSCP or BGS-CIEP Load. This determination will be made by the Auction Manager in consultation with the EDCs and the Board Advisor.

In the event that the auction volume is reduced to less than 100 percent of BGS-RSCP or BGS- CIEP Load, PSE&G will implement a contingency plan for the remaining tranches. Under that plan, PSE&G, at its option, will purchase necessary services for the remaining tranches through PJM-administered markets until May 31, 2023. After May 31, 2023 any unfilled tranches may be included in a subsequent auction or treated as in Contingency Plans Part (c) below. This Contingency Plan will alert bidders that in order to secure BGS-RSCP or BGS-CIEP prices from New Jersey BGS customers for their supply, it will be necessary to bid in the auctions. Failure to bid will mean that the BGS market faced by suppliers will be a spot market with volatility and related risks.

Since the contingency plan calls for the purchase of BGS supply in PJM-administered markets, it is considered a strong feature of the auction proposal because it provides bidders a strong incentive to participate in the Auction Process. If bidders were to believe that a less than fully subscribed auction would lead to a negotiation or a secondary market in which PSE&G, on behalf of its customers, would seek to acquire fixed priced supplies, the incentive to participate in the auction and the incentive to offer the best prices in the auction would be diminished.

(b) Defaults prior to June 1st 2022.

If a winning bidder defaults prior to the beginning of the BGS service, then, at the option of the EDC, the open tranches may be offered to the other winning bidders or these tranches may be bid out or procured in PJM-administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

(c) Defaults during the Supply Period

If a default occurs during the June 1, 2022 through May 31, 2025 period, at the option of PSE&G, the available tranches may be offered to other winning bidders, bid out, or procured in PJM administered markets. Additional costs incurred by PSE&G in implementing this Contingency Plan will be assessed against the defaulting supplier's credit security.

II. ACCOUNTING AND COST RECOVERY

The accounting and cost recovery that PSE&G proposes for its BGS service is summarized in this section. These provisions are intended to be applicable to PSE&G only. Each EDC will provide individual BGS cost recovery proposals.

BGS-RSCP AND BGS-CIEP RECONCILIATION CHARGES

PSE&G's BGS accounting will account for BGS-RSCP revenues and BGS-CIEP revenues individually as follows:

1. BGS-RSCP and BGS-CIEP revenues will be tracked using established accounting procedures and recorded separately as BGS-RSCP revenue and BGS-CIEP revenue;
2. As previously established for PSE&G, uncollectible revenues are recovered through a component of PSE&G's Societal Benefits Charge.

PSE&G will account for BGS-RSCP and BGS-CIEP costs individually as the sum of the following:

1. Payments made for the provision of BGS-RSCP or BGS-CIEP service;
2. Any administrative costs associated with the provision of BGS-RSCP and BGS- CIEP service;
   a. Administrative costs are defined as commonly-incurred or directly-incurred. *Commonly-incurred costs* are costs shared among all of the New Jersey Electric Distribution Companies (the "EDCs"). *Directly-incurred costs* are costs specifically incurred by each EDC, individually.

   Commonly-incurred costs include, but are not limited to, the following:

- preparing and conducting the annual auction, which include all pre-auction development work, developing and printing materials, developing and maintaining the BGS auction website, conducting information sessions for prospective bidders, as well as other consulting services provided by the Auction Manager;
- oversight of the auction process on behalf of the New Jersey Board of Public Utilities (the "Board or "BPU"), as performed by the Board's consultant.
- rent and maintenance of office space in New Jersey for the Auction Manager;
- outside counsel legal costs associated with the prosecution and/or defense of BGS patent claims; and
- facility costs associated with viewing the annual auction in real time, which include, but are not limited to, costs for physical space and equipment/media connections.

Directly-incurred costs (for PSE&G) include, but are not limited to, the following:

- GATS Administrative Fee
- Printing Costs of Environmental Label inserts

The commonly-incurred cost estimates for each BGS Auction cycle are paid for by the winning bidders of the auction at the start of each Energy Year through the Tranche Fee. The difference between the estimated commonly-incurred costs and the actual commonly-incurred costs and all the directly-incurred costs are paid through the BGS Reconciliation Charges.

As noted, one element of commonly-incurred costs have been the costs associated with the rent and maintenance of office space in New Jersey for the Auction Manager to conduct the annual BGS Auction. Due to restrictions and safeguards related to the COVID-19 pandemic, the February 2021 BGS Auction was conducted remotely (ie. the aforementioned office space was not utilized), without issue. Given the success of conducting the recent auction in this manner, PSE&G believes that it would be prudent (and will reduce costs for the benefit of BGS customers) to conduct future BGS Auctions in this same remote manner. As such, the Company proposes to begin the process of subletting or otherwise closing the physical BGS office located in Newark, N.J., in an effort to eliminate the costs related to the same.

Additionally, in response to a recommendation included in the BGS Administrative Expense audit (BPU Docket No. EA1701004), PSE&G has evaluated its administrative costs and identified additional directly incurred costs that are common across the EDCs and related to the provision of BGS service. The Company plans to ultimately account for such costs similar to other directly incurred BGS administrative costs (i.e. recoverable through the reconciliation charge(s)), following its next base rate case.

3. The cost of any procurement of necessary services including capacity, energy, ancillary services, transmission, RPS compliance, and other expenses related to the Contingency Plan less any payments recovered from defaulting suppliers.

Adjustment type (ie. reconciliation) charges are necessary in order to balance out the difference between (1) the monthly amounts paid within the quarter to the BGS-RSCP and BGS-CIEP supplier(s) for BGS-RSCP and BGS-CIEP supply and (2) the total revenue from customers for BGS-RSCP and BGS-CIEP services within the quarter, respectively.

These reconciliation charges are calculated separately each quarter for BGS-RSCP and BGS- CIEP and applied for the upcoming quarter on a dollars per kWh basis and the respective rates are applied to all BGS-RSCP and BGS-CIEP kWh billed. These charges are combined with BGS-RSCP and hourly BGS-CIEP charges for billing although they are published in separate BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge tariff sheets that are revised quarterly to reflect actual revenues and costs. These tariff sheets are filed with the Board approximately 15 days prior to the first day of the effective quarter.

The BGS-RSCP reconciliation charge and BGS-CIEP reconciliation charge are subject to deferred accounting with interest at the NGC rate previously set by the Board and are determined individually as set forth below:

The reconciliation charges are used in both BGS-RSCP and BGS-CIEP to true up the differences between BGS payments to suppliers and BGS revenues from customers for the quarter. Differences in BGS costs and BGS revenues for a quarter are computed in the following month and applied to BGS rates for the upcoming quarter. Two of these differences are shown below:

1. The difference between BGS Costs (as defined above) paid to suppliers for each month in the quarter and each calendar month of BGS revenue in the quarter. This difference is calculated in each month after the quarter to become effective in the upcoming quarter.
2. The difference between the total adjustment charge revenue intended to be recovered in the quarter and the actual adjustment charge revenue recovered in the quarter. This difference is driven by differences between actual kWh in the quarter and the kWh used to calculate the charge.

The reconciliation charges to be applied in the upcoming quarter are calculated as the net of the two differences described above for the quarter (plus or minus any cumulative under or over recovery from the prior quarter) divided by the forecast of BGS kWh in upcoming quarter.

The following table summarizes PSE&G's proposed process:

Reconciliation for the Months of:	Quarterly Rate In Effect:
February – April	June – August 31
May – July	September – November 30

August – October	December – February 28
November – January	March – May 31

III. DESCRIPTION OF BGS TARIFF SHEETS AND OTHER TARIFF ITEMS

GENERAL

As described in the generic section of this filing, two different methods will continue to be utilized for the pricing of BGS default supply service to customers: Basic Generation Service – Residential Small Commercial Pricing (BGS-RSCP) for residential and small commercial customers and Basic Generation Service – Commercial and Industrial Energy Pricing (BGS-CIEP), a variable hourly energy pricing for large commercial and industrial customers.

The Company is not proposing any modification of the criteria for BGS-CIEP eligibility from the current peak load share of 500kW. Thus BGS-CIEP is proposed to continue to be the default service for all customers served under delivery rate schedules HTS-High Voltage, HTS-Subtransmission, and LPL-Primary and for LPL-Secondary customers with a peak load share (PLS) of 500 kW or higher.

As in prior years, all other non-residential customers also have the option of electing BGS-CIEP as their default supply service. All non-residential customers with BGS-CIEP as their optional default service will be notified of their option to switch to BGS-CIEP through PSE&G's website and tariffs. Annually, customers eligible for this option must notify PSE&G no later than the second business day of January of any given year to have BGS-CIEP as their default supply service option for the annual period beginning June 1st of that year. The BGS-RSCP default service will be available to residential and small and medium sized non-residential customers, specifically those served on Rate Schedules RS, RHS,

RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (PLS less than 500 kW).

The following sections describe the tariff sheets that would implement Public Service's BGS service effective June 1, 2022.

BGS-RSCP

While Public Service is not proposing any change in the structure of the BGS-RSCP default supply service, the BGS Transmission Charges continue to be shown separately. The form of the BGS-RSCP tariff sheets are included in Attachment 1 and are indicated as Sheet Nos. 75, 76, and 79. Once the results of the BGS-RSCP Bid are finalized, the values on these tariff sheets will be updated reflecting the results of the bid.

As indicated on these form of tariff sheets, the BGS-RSCP default service is made up of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges. These charges will apply for usage in the calendar months of June through September, or October through May, as applicable.

BGS Energy Charges

The values of the BGS Energy charges applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL include the costs related to energy, ancillary services and generation capacity costs. This overall approach is a continuation of the current approved methodology of recovering all electric supply service costs in the kilowatt-hour charges for these rate schedules.

Typically, the generation capacity costs used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2022/2023, 2023/2024, and 2024/2025 Base Residual Auction ("BRA") results under the Reliability Pricing Model ("RPM") applicable to load served in the PSEG zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy Prices.

However, PJM has issued a schedule of upcoming BRAs and the recently conducted BRA produced a preliminary price paid for capacity of $97.75 per MW-day for the 2022/2023 Delivery Year for the PSE&G Zone. Due to the postponement of the BRAs, contracts from the 2020 and 2021 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2022/2023 Delivery Year and the 2023/2024 Delivery Year, a Capacity Proxy Price of $162.13 per MW-Day was used in place of the 2022/2023 BRA value and a Capacity Proxy Price of $166.64 per MW-Day was used in place of the 2023/2024 BRA value.

Given the continued delay in the schedule of BRAs for the 2023/2024 Delivery Year and 2024/2025 Delivery Year, a Capacity Proxy Price of $128.79 per MW-Day and a Capacity Proxy Price of $87.98 per MW-Day have been used in place of the prices paid for capacity for 2023/2024 and 2024/2025 Delivery Years, respectfully.

For Energy Year (EY) 2024, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2023/2024 Delivery has not occurred at least 20 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the "Zonal Capacity Price", which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2023/2024 Delivery Year.

For Energy Year (EY) 2025, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2024/2025 Delivery has not occurred at least 20 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2024/2025 Delivery Year.

PSE&G will file new tariff sheets for EY 2024 and EY 2025, reflecting the impact of this price adjustment, in a manner similar to Attachment 4, Page 1 – Development of Capacity Proxy Price True Up - $/MWh. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements. Attachment 4, Pages 2 and 3 are illustrative examples of how of how the Capacity Proxy Price True Up will be calculated for EY 2024 and EY 2025 respectively and prospectively.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2020 and February 2021 are still in effect for approximately two-thirds of the load for Energy Year 2023 (the year beginning June 1, 2022). Payments to BGS-RSCP Suppliers that executed the Supplements to the SMAs approved by the BPU on November 13, 2019 and November 18, 2020 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2022/2023 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time, PSE&G will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in February 2020 and February 2021. The value of the recently conclude BRA in June of 2021 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2022/2023 Delivery Year ($97.75 per MW-Day).

The generation capacity and transmission related costs will continue to be recovered through separate charges for customers on Rates GLP and LPL-Secondary (less than 500 kW) based on the customer specific assigned generation capacity and transmission obligation values. The resulting BGS Energy

Charges applicable to this latter set of customers thus do not include the costs related to generation capacity and transmission service.

In order to more accurately reflect the costs of providing energy and other electric services when relying on the day-ahead PJM verses the real-time markets, the Company will apply two ancillary services costs, one applied to BGS-RSCP service and the other applied to BGS-CIEP service. A $2.00 per MWh ancillary services rate is used in the calculation of the BGS-RSCP rates since it is more reflective of costs borne in the day-ahead market. Additionally, Renewable Portfolio Standard costs estimated to be $15.26 per MWh are included in the calculation of the BGS-RSCP rates to reflect compliance costs. A BGS-CIEP ancillary services cost of $6.00 per MWh is applied since it is more reflective of costs borne in the real-time market.

The specific values that will be utilized for the BGS Energy Charges will be calculated from the winning BGS-RSCP bid prices for the Public Service zone. It is the intent of the EDCs that the factors in the tables will be applied to the tranche-weighted average winning bid prices adjusted for seasonal payment factors resulting from the auctions for BGS-RSCP with terms covering the period from June 1, 2022 to May 31, 2023. For example, for Public Service, for the period beginning June 1, 2022, the weighting will be based on the load (i.e. successfully bid tranches) at the 36-month prices from the 2020, 2021, and 2022 BGS-RSCP auctions, and the seasonal payment factors calculated in Attachment 2.

The tables will be updated annually, prior to future BGS auctions and utilized to develop customer charges for a related annual period in a similar manner as discussed above. The updates will reflect then current factors such as updated futures prices, factors based on 12- month data, and any changes in the customer groups and loads eligible for the BGS-RSCP class.

BGS Capacity Charges

These charges are the separate charges previously mentioned that are designed to recover the costs associated with generation capacity for customers served on Rate Schedules GLP and LPL-Secondary (less than 500 kW). These charges are expressed on a per-kW of generation capacity obligation basis.

Typically, the generation capacity costs designed to be used in the development of the BGS-RSCP rates are the relevant current wholesale market prices for capacity based on the average, 2022/2023, 2023/2024, and 2024/2025 BRA for RPM results applicable to load served in the PSEG zone. This process has been impacted in recent years by delays in conducting the BRAs – resulting in the need for contract supplements with Capacity Proxy prices. However, PJM has issued a schedule of upcoming BRAs and the recently conducted BRA produced a preliminary price paid for capacity of $97.75 per MW-day for the 2022/2023 Delivery Year for the PSE&G Zone. Due to the postponement of the BRAs, contracts from the 2020 and 2021 BGS auctions contained supplements with Capacity Proxy Prices. With the prior postponements of the BRAs for the 2022/2023 Delivery Year and the 2023/2024 Delivery Year, a Capacity Proxy Price of $162.13 per MW-Day was used in place of the 2022/2023 BRA value and a Capacity Proxy Price of $166.64 per MW-Day was used in place of the 2023/2024 BRA value.

Given the continued delay in the schedule of BRAs for the 2023/2024 Delivery Year and 2024/2025 Delivery Year, a Capacity Proxy Price of $128.79 per MW-Day and a Capacity Proxy Price of $87.98 per MW-Day have been used in place of the prices paid for capacity for 2023/2024 and 2024/2025 Delivery Years, respectfully.

For Energy Year (EY) 2024, if Supplement A to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2023/2024 Delivery has not occurred at least 20 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the difference between the “Zonal Capacity Price”, which is the price paid by BGS-RSCP Suppliers for

Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2023/2024 Delivery Year.

For Energy Year (EY) 2025, if Supplement B to the BGS-RSCP Supplier Master Agreement is approved by the BPU and the BRA for the 2024/2025 Delivery has not occurred at least 20 business days prior to the BGS-RSCP Auction, payments to BGS-RSCP Suppliers will be adjusted for the capacity price difference between the Zonal Capacity Price, which is the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone, as may be determined under the Reliability Pricing Model or its successor or otherwise, and the Capacity Proxy Price for the 2024/2025 Delivery Year.

PSE&G will file new tariff sheets for EY 2024 and EY 2025, reflecting the impact of this price adjustment. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements.

The Supplements to the SMAs signed by BGS-RSCP Suppliers in February 2020 and February 2021 are still in effect for approximately two-thirds of the load for Energy Year 2023 (the year beginning June 1, 2022). Payments to BGS-RSCP Suppliers that executed the Supplements to the SMAs approved by the BPU on November 13, 2019 and November 18, 2020 will be adjusted for the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2022/2023 Delivery Year. Upon the conclusion of the Third Incremental RPM Auction, or the RPM's successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. At that time, PSE&G will file new tariff sheets reflecting the impact of the Supplements. The rate design spreadsheets include the formulas that will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS-RSCP Suppliers in February 2020 and February 2021. The value of the recently conclude BRA in June of 2021 is used as an approximation for the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for the 2022/2023 Delivery Year ($97.75 per MW-Day).

BGS Transmission Charges

Similar to the BGS Capacity Charges, the BGS Transmission Charges recover the customer specific costs associated with network transmission service for customers on Rates GLP and LPL-Secondary (less than 500 kW). The charge is based on the annual transmission rate for network service for the PSE&G zone, as stated in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS Transmission Charge. The bids will exclude BGS Transmission Charges that will be in effect on January 1, 2022. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission-related charges in the PJM OATT at a minimum of twice per year for the rates to become effective January 1 and June 1 of each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of a cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used. For the BGS-RSCP energy only rates (Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL), upon BPU approval, changes in the OATT rate (per kW of transmission obligation) will be implemented by multiplying such change in the OATT rate by each rate class' ratio of the kW of transmission load of that class divided by the expected annual kWh of that class. The results, in dollars per kWh, will then be added to all BGS-RSCP Energy charges for each class.

In the event that PJM institutes a charge for transmission network service on an energy basis (per kWh), this charge will be added to the BGS-RSCP Energy charges for all kWhs for all rate schedules.

For prior BGS Contracts EY 2020, the BGS price will be adjusted to remove the BGS Transmission Charge as shown in Attachment 5 - Development of Assumed Transmission Price in Bids. The Transmission Obligations and kWh used per tranche are the same as were used in the BGS Pricing Spreadsheet at the time of the BGS Auctions held in February of 2020.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-RSCP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-RSCP energy charge for billing on a monthly basis.

BGS-CIEP

The bid product in the 2021 BGS-CIEP auction will continue to be the Generation Capacity Cost, as it was in last year's BGS-CIEP auction. Public Service will continue the use of a value for the CIEP Standby Fee equal to 0.000150 dollars per kWh.

The form of tariff sheets for the Basic Generation Service – Commercial and Industrial Energy - Pricing (BGS-CIEP) are included in Attachment 1 and are indicated as Sheet Nos. 73, 82, and 83.

Similar to the BGS-RSCP, the charges for BGS-CIEP are comprised of several components: BGS Energy Charges, BGS Capacity Charges, BGS Transmission Charges, and the BGS Reconciliation Charges.

BGS Energy Charges

The primary component of this charge will be the actual PJM load-weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) of energy for the Public Service Transmission Zone.

To this will be added an ancillary service cost (including PJM Administrative Costs) for the Public Service zone of $6.00 dollars per MWh that was estimated as being reflective of ancillary service costs in the PSEG zone for energy purchased in the real time market. This sum will then be adjusted for losses. Because the LMPs are calculated to include a marginal loss component for the transmission system, a loss correction is performed. This is done by removing the mean hourly marginal transmission loss factor for the PSE&G transmission zone (equal to 0.71614%) from the BPU-approved PSE&G delivery tariff loss factors. The result is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated).

BGS Capacity Charges

These charges will recover the costs associated with generation capacity. The BGS Capacity Charge component of the BGS-CIEP bid is set equal to the BGS-CIEP auction clearing price. These charges are expressed on a per-kW of generation capacity obligation basis.

BGS Transmission Charges

BGS-CIEP Transmission Charges recover the customer specific costs associated with Transmission service for customers on BGS-CIEP. The charges are based on the annual transmission rate for network transmission service for the PSE&G zone, in PJM's Open Access Transmission Tariff (OATT), and as approved by the BPU for inclusion in the BGS-CIEP Transmission Charges. This charge is expressed as a monthly charge on a per-kW of transmission obligation basis. PSE&G will file with the BPU to change the transmission cost components of the BGS charges to customers as FERC approves changes in the Network Integration Transmission Service rates for the PSE&G zone in the PJM OATT, or the FERC approves other network transmission- related charges in the PJM OATT at a minimum of twice per year for the rates to become effective January 1 and June 1 or each year. To the extent that there is a change to the payments required by PJM for transmission, either as a result of a change in the firm transmission rate or as a result of a cost reallocation, PSE&G will present an additional filing to the Board to change the transmission charge paid by BGS customers. PSE&G will review and verify the basis for any BGS transmission charge adjustment and will file supporting documentation from the OATT, as well as any rate translation spreadsheets used.

BGS Reconciliation Charge

The BGS Reconciliation Charge for the BGS-CIEP default service is explained in the prior Section II - Accounting and Cost Recovery and will be combined with the BGS-CIEP energy charge for billing on a monthly basis.

OTHER ITEMS

CIEP STANDBY FEE

PSE&G will continue to pay each BGS-CIEP supplier a CIEP Standby Fee, which is set at 0.000150 dollars per kWh times their pro-rata share of the total energy usage measured at the meters of all of PSE&G's customers whose default service option is limited to BGS-CIEP and those customers who have elected BGS-CIEP as their default supply.

A tariff sheet, included in Attachment 1 and indicated as Sheet No. 73, shows the CIEP Standby Fee as a Delivery Charge that is applicable to all customers having BGS-CIEP as their sole default supply service option and those customers who have elected BGS-CIEP as their default supply. This includes all customers served on Rate Schedules LPL-Secondary (peak load share of 500 kW or greater), LPL-Primary, HTS-Subtransmission, HTS-High Voltage, and all customers on Rate Schedules HS, GLP, and LPL-Secondary (less than 500 kW) that have elected the BGS-CIEP default supply option.

DESCRIPTION OF BGS PRICING SPREADSHEETS

As described in the generic write-up, the resulting charge for each BGS rate element (i.e. Rate RS summer charge, winter charge, etc.) for the non-hourly BGS supply service will generally be based on factors applied to the tranche-weighted average winning bid prices adjusted for seasonal payments. These factors have been developed based on the ratios of the estimated underlying market costs of each rate element (for each rate class) to the overall all-in BGS cost. The tables included in Attachments 2 and 3 present all of the input data, intermediate calculations, and the final results in the calculation of these factors.

The following is a description of the calculations shown in the spreadsheet titled "Development of BGS-RSCP Cost and Bid Factors for the 2022/2023 BGS Filing", and included as Attachment 2.

Table #1 (% Usage during PJM On-Peak Period) contains the percentage of on-peak load, inputted by month, for each rate schedule. The on-peak period as used in this table (referred to as PJM periods) is defined as the 16-hour period from 7 AM to 11 PM, Monday through Friday. All remaining weekday hours and all hours on weekends and holidays recognized by the National Electric Reliability Council (NERC) are considered the off-peak period. This is consistent with the time periods used in the forwards market for trading of bulk power. The values in this table for each month are the average on-peak percentages from the years 2018 and 2019 and 2020, as calculated from the same load research data used for retail settlement for current customers that have chosen to be supplied by a Third Party Supplier (TPS). The average for a three-year period was used to reduce the variability of weather effects on the percentage from any single year.

Table #2 (% Usage During PSE&G On-Peak Billing Period) contains the percentage of on-peak load, by month, for each applicable rate schedule based on the definitions of time periods as contained in Public Service's delivery rate schedules. Since, excluding the hourly price BGS rates, only Rate Schedule RLM and LPL-Sec are billed on a time-of-day basis utilizing time periods, these are the only two columns in this table where data has been inputted. These are the percentage of actual on-peak kWh usage for the years 2018, 2019, and 2020. As was done with Table #1, the three-year average was used to reduce the effects of weather in a particular year.

Table #3 (Class Usage @ customer) contains the total calendar month sales forecasted for the calendar year 2021 with a migration adjustment. The values in Table #3 will be updated in January 2022 to better reflect the amount by rate schedule that could be in effect starting on June 1, 2022. For Rate LPL-Secondary, these values have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater, and thus having BGS- CIEP as their default service. These monthly percentages were based on the 2020 monthly percentages of total actual sales for customers meeting this Peak Load Share threshold.

Table #4 (Forwards Prices – Energy Only @ Bulk System) contains the forward prices for energy, by time period and month for the BGS analysis period. These values are the most recent energy on-peak forwards values available for the PJM West trading hub for the period of June 2022 to May 2023 and the historical ratio of actual off-peak to on-peak PJM LMPs from June 2018 through September 2020 and March 2018 through February 2021, for summer and winter periods, respectively.

An adjustment of the forwards prices contained in Table #4 is then made to correct for the effects of transmission congestion in the PJM system between the PJM West trading hub and the Public Service zone where the BGS supply will be utilized.

Table #5 (Congestion Factors) contains an estimate of the average congestion factors, by month and time period, which when multiplied by the prices at the PJM West trading hub will result in costs for power delivered into the Public Service zone. These Hub-to-Zone differentials are based on the average percent differences from June 2018 through September 2020 and March 2018 through February 2021, for summer and winter periods, respectively.

Table #6 (Losses) The factors utilized for total average losses, including PJM losses, are inputted in the upper portion of Table #6 (Losses) by rate schedule. Delivery loss factors used are those in the Company's filed tariff. PJM losses are the average percentage PJM EHV losses plus inadvertent energy for the three-year period June 2013 through May 2016, a value equal to 0.456%.

The lower portion of this table shows the derivation of the effective losses from the customer meter to the transmission nodes at which the LMPs are calculated. The loss factors shown are the Delivery loss factors from the Company's filed tariff less the mean hourly marginal loss factors for the PSE&G transmission zone as calculated by PJM. The resulting loss factor is reflective of losses from the customer meter to the transmission nodes (at which the LMPs are calculated) and at which payments to the winning bidders are based. The marginal loss factors used above are actual marginal loss de-ration factors based May 2018 to April 2021 data adjusted for the portion of marginal losses attributed to PJM extra-high voltage.

Since the service for all of the rates indicated is at secondary voltages, the applicable loss factors are identical for all rates.

Table #7 (Summary of Average BGS Energy Only Unit Costs @ Customer – PJM Time Periods) is the calculation of the energy only costs by rate, time period and season. These values are the seasonal and time period average costs per MWh as measured at the customer billing meter (from Table #3), based on the forwards prices (from Table #4) corrected for congestion (from Table #5), losses (from Table #6), and monthly time period weights (from Table #1). These average costs do not include the costs associated with Ancillary Services, Renewable Portfolio Standard compliance, Generation Obligation or Transmission costs, which will be considered in subsequent calculations.

Table #8 (Summary of Average BGS Energy Only Costs @ Customer – PJM Time Periods) indicates the total value, in thousands of dollars, of the average BGS energy only costs. These are the results of the multiplication of the unit costs from Table #7, the monthly time period weights from Table #1 and the total sales to customers from Table #3.

Since the end result of these calculations are to be utilized in the development of retail BGS rates, the rates utilizing time-of-day pricing must be developed based upon the time periods as defined for billing.

Table #9 (Summary of Average BGS Energy Only Unit Costs @ Customer – PSE&G Time Periods) shows the result of the corrections for the two rates billed on a time-of-day basis, Rates RLM and LPL-Secondary (less than 500 kW). These values are calculated based on the assumption that the MWhs included in the PJM on-peak time period and not included in the PSE&G on-peak time periods are at the average of the on and off-peak PJM prices.

Table #10 (Generation & Transmission Obligations and Costs and Other Adjustments) The next steps set up the values necessary for the inclusion of the costs of the Generation Capacity and Transmission obligations. The top portion of Table #10 shows the total obligations with a migration adjustment, by rate schedule, that are currently being utilized in the year 2021. The values in the top portion of Table #10 will be updated in January 2022 to better reflect the aggregate amount by rate schedule that could be in effect on June 1, 2022. Similar to the methodology used in Table #3, the obligations for Rate LPL-Secondary have been reduced for the percentage of customers having a Peak Load Share of 500 kW or greater. The middle portion of this table shows the number of summer and winter days and months that are used in this analysis. The bottom portion of this table shows the annual cost for transmission service now to be zero and the average price of generation capacity, using the relevant RPM auction result for Delivery Year 2022/2023, the Capacity Proxy Price for Delivery Year 2023/2024, and the Capacity Proxy Price for Delivery Year 2024/2025. The Capacity Proxy Price will be replaced with the Zonal Capacity Prices, which are the prices paid by BGS-RSCP Suppliers for Capacity for the 2023/2024 and the 2024/2025 delivery years, when available as may be determined through the Reliability Pricing

Model or its successor or otherwise.

The BGS Transmission Charge will now be set through separate filings as discussed in the BGS Transmission Charge sections. This table also shows the level of blocking in current BGS charges for Rates RS and RHS, which will be utilized in the later calculations of the blocking of the new BGS charges for these rates. The Company has previously objected to the blocking of these charges since there is no compelling cost basis for any such blocking. The Company proposes to keep blocking in this year's filing, but wishes to note that it does not believe that there is a cost basis for doing so.

Table #11 (Ancillary Services and Renewable Portfolio Standard) An estimate of the effects of the costs of ancillary services and Renewable Portfolio Standard is included in the development of the final BGS rates. The values of $2.00 per MWh and $15.26 per MWh are used, respectively. Since the actual costs are a complex combination of many factors, this Board-approved estimate of the overall annual average value, expressed on a dollar per MWh basis, is used as a reasonable and practical alternative.

Table #12 (Summary of Obligation Costs Expressed as $/MWh @ Customer – For Non- Demand Rates Only) shows the result of the allocation of both the transmission and generation costs on a per kWh basis to those rates whose BGS service will only be recovered through energy charges, Rates RS through BPL. The obligation costs for the rates not indicated in this table, Rates GLP and LPL-Sec, will be recovered directly through a distinct obligation charge based on a separate charge times each customer's assigned transmission and generation capacity obligation. The annual values are calculated as the total obligations (upper part of Table #10) times their costs (lower part of Table #10) divided by the appropriate total rate schedule MWh (from Table #3).

Table #13 (Summary of BGS Unit Costs @ Customer) is the result of the inclusion of the Transmission, Generation Capacity, Ancillary Services, and Renewable Portfolio Standard costs to the energy only costs shown in Table #9. The top portion of this table shows the total estimated all-in BGS costs for the non-demand rates (Rates RS, RHS, RLM, WH, WHS, HS, PSAL and BPL), whose BGS costs are proposed to be recovered on an energy only basis through kWh charges. The all-in costs for the residential non-time of day rates, Rates RS and RHS, are blocked in the summer based on the current level of BGS blocking inputted in Table #10 so as to maintain the same BGS rate differential that currently exists. The middle section shows the results for the demand rates (Rates GLP and LPL-Sec) whose BGS costs will be recovered through both energy charges on a per kWh basis and obligation charges on a per kW of obligation basis. The left hand columns indicate the unit energy costs, while the right hand columns indicate the obligation costs. The bottom portion of this table shows the total estimated costs for BGS, based on the assumptions utilized in the above tables, and the average per unit cost, as measured at the customer meters or the transmission nodes.

Table #14 (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ Transmission Nodes) indicates the ratio of the individual rate element costs from Table #13 to the overall all- in cost as measured at the transmission nodes, plus constants, where applicable. These bid factor ratios are a key element in the calculation of the actual BGS-RSCP charges, and will be used in later tables to convert the winning bids into actual BGS rates charged to customers.

The top portion of this table indicates these ratios for the non-demand rates while the ratios for the demand rates are shown on the bottom portion of the table. Since the unit rates charged for generation and transmission obligation (as shown in the right hand columns) for Rates GLP and LPL-Sec are not unitized but kept at the estimated market value, it is necessary to modify the energy ratios for these two rate classes to assure that the resulting overall revenue from charges to the customers equals the payment to suppliers. The first of the values indicated, the “multiplier” is utilized as a ratio, with the “constant” term an additive adjustment to the resulting value. For example, if the tranche weighted average winning bid prices adjusted for seasonal payment factors is $52.436 per MWh and the GLP multiplier for summer is 0.976 and the constant is ($9.713), the summer BGS rate charged customers would equal ($52.436 * 0.976) - $9.713, or $41.46 per MWh.

Assumptions: This unnumbered table summarizes some of the most important assumptions utilized in the above calculations.

Table #15 (Summary of Total BGS Costs by Season) shows the calculation of the total BGS Costs, utilizing the total customer usage from Table #3 and the all-in unit costs from Table #13. The lower left portion of this table indicates the relative percentage of total costs by season for all rate schedules, while the center shows the calculation of the overall average all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall average seasonal costs to the overall total cost, shown in the lower right hand portion of this table, are the seasonal payment ratios upon which payments to the winning bidders are based. Since the normal calculation would produce an atypical result of a summer payment ratio (factor) that is lower than the winter payment ratio (factor) for the 2022/2023 BGS Supply Period, a factor of 1.0 will be used for both the summer and winter payment factors.

Table #16 (Spreadsheet Error Checking) shows the reconciliation between the customer revenue calculation to the BGS supplier payments, utilizing an assumed winning bid price (as indicated) and the calculated summer-winter payment ratios, the customer usage from Table #3 and the all-in unit costs from Table #13.

Table #17 (Total Supplier Energy @ transmission nodes) shows the calculation of the total supplier energy by season, utilizing the total customer usage from Table #3 and the meter to transmission node loss factors from the lower portion of Table #6.

The second spreadsheet used in the calculation of the final BGS-RSCP rates is included as Attachment #3, and is titled “Calculation of June 2022 to May 2023 BGS-RSCP Rates”. The tables in this spreadsheet calculate the weighted average winning bid price and convert it into the final BGS-RSCP rates that are charged to customers. An explanation of each of the six tables, labeled as Table A through F, is as follows.

Table A (Auction Results) contains the results of the prior two BGS auctions as well as the results (shown with illustrative values) of the current auction. The Capacity Proxy Price True Up cost in $ per MWh will be used to reflect the impact of payments made pursuant to the Supplements executed by BGS Suppliers in February 2020 and February 2021. Upon conclusion of the Third Incremental RPM Auction through the Reliability Pricing Model or its successor or otherwise, the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone will be known. The Capacity Proxy Price True-Up will then be determined by the price difference between the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone and the Capacity Proxy Price for the 2022/2023 Delivery Year. The value of the recently concluded BRA in June of 2021 is used as an approximation of the price paid by BGS-RSCP Suppliers for Capacity in the Company's PJM Zone for 2022/2023.

The BGS Transmission Charges arrived at by the methods shown in Attachment 5 - Development of Assumed Transmission Price in Bids will be removed from prior winning bids. From these values, the weighted average annual bid price (shown on line #13) is calculated. All of the formulas used in this table are shown in the right hand column of this table, under the heading of "Notes:"

Table B (Ratio of BGS Unit Costs @ Customer to All-In Average Cost @ transmission nodes) is a repeat of the values shown in Table #14 from Attachment 2, the bid factors calculated based on current market conditions.

Table C (Preliminary Resulting BGS Rates) contains the preliminary customer BGS-RSCP rates as the product of the weighted average bid price (from Table A) and the Bid Factors from Table B.

Table D (Revenue Recovery Calculations) contains a comparison of the total anticipated rate revenue billed to customers based on the preliminary BGS-RSCP rates developed in Table C and the anticipated total season payments to BGS suppliers, based on the data in Table A. The calculation of the kWh Rate Adjustment Factors are also done in this table, which are equal to the seasonal dollar differences between the anticipated billed revenue and supplier payments, divided by the total anticipated seasonal billed BGS-RSCP energy related charges.

Table E (Final Resulting BGS Rates) contains the final adjusted BGS-RSCP rates, which are equal to the preliminary BGS–RSCP rates shown in Table C times the seasonal kWh Rate Adjustment Factors that were developed in Table D.

Table F (Spreadsheet Error Checking) contains a comparison of the total anticipated rate revenue billed to customers based on the final BGS-RSCP rates developed in Table E and the anticipated total season payments to BGS suppliers, based on the data in Table A.

IV. CONCLUSION

In connection with the approval of this filing, the Company requests that the Board determine:

1. It is necessary and in the public interest for the electric public utilities to secure service for the BGS-RSCP and BGS-CIEP customers, as approved herein, for the period June 1, 2022 to May 31, 2025.
2. The Company's proposed accounting for BGS is approved for purposes of accounting and BGS cost recovery.
3. The proposed BGS Contingency Plan is approved, and there will exist a presumption of prudence with respect to the BGS Auction Plan method and the costs incurred for BGS service under the Auction Plan and the related Contingency Plan.

4. The Company's Rate Design Methodology and Tariff Sheets are approved.

V. ATTACHMENT 1 - TARIFF SHEETS

"Form Of" BGS-RSCP, BGS-CIEP and CIEP Standby Fee tariff sheets

(Pages 1 through 6)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

B.P.U.N.J. No. 16 ELECTRIC **Original Sheet No. 73**

COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) STANDBY FEE

APPLICABLE TO:

All kilowatt-hour usage under Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and all kilowatt-hour usage for customers under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected hourly energy pricing service from either BGS-CIEP or a Third Party Supplier.

	Charge (per kilowatt-hour)
Commercial and Industrial Energy Pricing (CIEP) Standby Fee	$ 0.000150
Charge including New Jersey Sales and Use Tax (SUT)	$ 0.000160

The above charges shall recover costs associated with the administration, maintenance and availability of the Basic Generation Service default electric supply service for applicable rate schedules. These charges shall be combined with the Distribution Kilowatt-hour Charges for billing.

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

Date of Issue: October 30, 2018 Effective: November 1, 2018
Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated October 29, 2018
in Docket Nos. ER18010029, GR18010030, AX18010001 and ER18030231

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 75**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY & CAPACITY CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Energy & Capacity Charges	Charges Including SUT	Energy & Capacity Charges	Charges Including SUT
RS – first 600 kWh	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx
RS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – first 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RHS – in excess of 600 kWh	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy, Generation Capacity, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES:

Applicable to Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF and PSAL

Charges per kilowatt-hour:

	For usage in all months	
Rate Schedule	Transmission Charges	Charges Including SUT
RS	$ x.xxxxxx	$ x.xxxxxx
RHS	x.xxxxxx	x.xxxxxx
RLM On-Peak	x.xxxxxx	x.xxxxxx
RLM Off-Peak	x.xxxxxx	x.xxxxxx
WH	x.xxxxxx	x.xxxxxx
WHS	x.xxxxxx	x.xxxxxx
HS	x.xxxxxx	x.xxxxxx
BPL	x.xxxxxx	x.xxxxxx
BPL-POF	x.xxxxxx	x.xxxxxx
PSAL	x.xxxxxx	x.xxxxxx

The above charges shall recover all costs related to the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and allocated to the above Rate Schedules. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
GLP	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx	$ x.xxxxxx
GLP Night Use	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
LPL-Sec. under 500 kW				
On-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx
Off-Peak	x.xxxxxx	x.xxxxxx	x.xxxxxx	x.xxxxxx

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 79**

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September ....$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx
Charge applicable in the months of October through May...$ x.xxxx
Charge including New Jersey Sales and Use Tax (SUT) ....$ x.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC .... $xxx,xxx.xx per MW per year
EL05-121……. ....$ xx.xx per MW per month
FERC 680 & 715 Reallocation……. ....$ xxx.xx per MW per month
PJM Seams Elimination Cost Assignment Charges...................................$ x.xx per MW per month
PJM Reliability Must Run Charge...$ x.xx per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ xx.xx per MW per month
Virginia Electric and Power Company ....$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ xx.xx per MW per month
PPL Electric Utilities Corporation...$ xxx.xx per MW per month
American Electric Power Service Corporation ....$ xx.xx per MW per month
Atlantic City Electric Company. ....$ x.xx per MW per month
Delmarva Power and Light Company...$ x.xx per MW per month
Potomac Electric Power Company. ....$ x.xx per MW per month
Baltimore Gas and Electric Company...$ x.xx per MW per month
Jersey Central Power and Light ....$ xx.xx per MW per month
Mid Atlantic Interstate Transmission...$ xx.xx per MW per month
PECO Energy Company……………………………….................$ xx.xx per MW per month
Silver Run Electric, Inc.……………………………… ....$ xx.xx per MW per month
Northern Indiana Public Service Company………………………… ..$ x.xx per MW per month
Commonwealth Edison Company ....$ x.xx per MW per month
Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months .... $ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT) .... $ xx.xxxx

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such change to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 82**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 82**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules LPL-Secondary (500 kilowatts or greater), LPL-Primary, HTS-Subtransmission, HTS-Transmission, HTS-High Voltage and to customers served under Rate Schedules HS, GLP and LPL-Secondary (less than 500 kilowatts) who have elected BGS-CIEP as their default supply service.

BGS ENERGY CHARGES:

Charges per kilowatt-hour:

BGS Energy Charges are hourly and include PJM Locational Marginal Prices, and PJM Ancillary Services. The total BGS Energy Charges are based on the sum of the following:

- The real time PJM Load Weighted Average Residual Metered Load Aggregate Locational Marginal Prices for the Public Service Transmission Zone, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.71614~~0.67126~~%), and adjusted for SUT, plus
- Ancillary Services (including PJM Administrative Charges) at the rate of $0.006000 per kilowatt-hour, adjusted for losses (tariff losses, as defined in Standard Terms and Conditions Section 4.3, adjusted to remove the mean hourly PJM marginal losses of 0.71614~~0.67126~~%), and adjusted for SUT, plus

BGS CAPACITY CHARGES:

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September .... $ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT) .... $ xx.xxxx

Charges applicable in the months of October through May .... $ xx.xxxx
Charges including New Jersey Sales and Use Tax (SUT)... $ xx.xxxx

The above charges shall recover each customer's share of the overall summer peak load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 83**

BASIC GENERATION SERVICE – COMMERCIAL AND INDUSTRIAL ENERGY PRICING (CIEP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC .... $xxx,xxx.xx per MW per year
EL05-121……..$ xx.xx per MW per month
FERC 680 & 715 Reallocation…….. ....$ xxx.xx per MW per month
PJM Seams Elimination Cost Assignment Charges...................................$ x.xx per MW per month
PJM Reliability Must Run Charge ....$ x.xx per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ xx.xx per MW per month
Virginia Electric and Power Company ....$ xx.xx per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....$ xx.xx per MW per month
PPL Electric Utilities Corporation..$ xxx.xx per MW per month
American Electric Power Service Corporation ....$ xx.xx per MW per month
Atlantic City Electric Company. ....$ x.xx per MW per month
Delmarva Power and Light Company..$ x.xx per MW per month
Potomac Electric Power Company. ....$ x.xx per MW per month
Baltimore Gas and Electric Company..$ x.xx per MW per month
Jersey Central Power and Light ....$ xx.xx per MW per month
Mid Atlantic Interstate Transmission...$ xx.xx per MW per month
PECO Energy Company……………………………….................$ xx.xx per MW per month
Silver Run Electric, Inc.………………………………… ....$ xx.xx per MW per month
Northern Indiana Public Service Company………………………… ..$ x.xx per MW per month
Commonwealth Edison Company ....$ x.xx per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months .... $ xx.xxxx
Charge including New Jersey Sales and Use Tax (SUT) .... $ xx.xxxx

The above charges shall recover each customer's share of the overall summer peak transmission load assigned to the Public Service Transmission Zone by the PJM Interconnection, L.L.C. (PJM) as adjusted by PJM assigned transmission capacity related factors and shall be in accordance with Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions. These charges will be changed from time to time on the effective date of such charge to the PJM rate for charges for Network Integration Transmission Service, including the PJM Seams Elimination Cost Assignment Charges, the PJM Reliability Must Run Charge and PJM Transmission Enhancement Charges as approved by Federal Energy Regulatory Commission (FERC).

Kilowatt threshold noted above is based upon the customer's Peak Load Share of the overall summer peak load assigned to Public Service by the Pennsylvania-New Jersey-Maryland Office of the Interconnection (PJM). See Section 9.1, Measurement of Electric Service, of the Standard Terms and Conditions of this Tariff.

VI. ATTACHMENT 2 - SPREADSHEETS FOR THE DEVELOPMENT OF BGS COST AND BID FACTORS

(Pages 1 through 7)

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Development of BGS-RSCP Cost and Bid Factors for 2022/2023 BGS Filing
Adjusted to Billing Time Periods

Based on average of year 2018,2019 & 2020 Load Profile Information

Table #1 **% Usage During PJM On-Peak Period**

On-Peak periods defined as the 16 hr PJM Trading period, adj for NERC holidays

(data rounded to nearest .01%)	*Profile Meter Data* RS	*Profile Meter Data* RHS	*Profile Meter Data* RLM	*Profile Meter Data* WH	*Profile Meter Data* WHS	*Profile Meter Data* HS	*--- Other Analysis ---* PSAL	BPL	*Profile Meter Data* GLP	*Profile Meter Data* LPL-S
January	49.17%	48.70%	48.93%	49.17%	49.17%	49.23%	31.40%	31.40%	55.50%	53.73%
February	48.23%	46.87%	47.87%	48.23%	48.23%	47.67%	29.10%	29.10%	54.77%	53.30%
March	48.77%	47.80%	48.07%	48.77%	48.77%	49.10%	24.83%	24.83%	54.63%	53.13%
April	50.40%	50.73%	50.13%	50.40%	50.40%	53.03%	23.00%	23.00%	56.63%	54.90%
May	48.77%	49.77%	49.93%	48.77%	48.77%	56.77%	20.83%	20.83%	56.07%	54.17%
June	50.70%	51.50%	52.57%	50.70%	50.70%	60.67%	19.73%	19.73%	57.27%	55.33%
July	50.97%	51.90%	52.87%	50.97%	50.97%	60.87%	19.80%	19.80%	57.90%	55.27%
August	52.30%	52.93%	53.57%	52.30%	52.30%	62.17%	21.57%	21.57%	58.33%	55.27%
September	48.37%	48.97%	49.30%	48.37%	48.37%	58.60%	22.60%	22.60%	55.47%	53.20%
October	52.23%	52.27%	52.27%	52.23%	52.23%	59.13%	27.73%	27.73%	59.00%	57.13%
November	47.30%	46.43%	46.63%	47.30%	47.30%	49.23%	30.30%	30.30%	53.63%	51.93%
December	47.73%	46.60%	47.60%	47.73%	47.73%	48.07%	30.83%	30.83%	52.80%	51.10%

Based on average of year 2018,2019 & 2020 Load Profile Information

Table #2 **% Usage During PSE&G On-Peak Billing Period**

On-Peak periods as defined in specified rate schedule (average of %s for 2018, 2019 & 2020)

(data rounded to nearest .01%)	*N/A* RS	*N/A* RHS	*Profile Meter Data* RLM	*N/A* WH	*N/A* WHS	*N/A* HS	*N/A* PSAL	*N/A* BPL	*N/A* GLP	*Profile Meter Data* LPL-S
January	0%	0%	43%	0%	0%	0%	0%	0%	0%	47%
February	0%	0%	42%	0%	0%	0%	0%	0%	0%	48%
March	0%	0%	42%	0%	0%	0%	0%	0%	0%	48%
April	0%	0%	42%	0%	0%	0%	0%	0%	0%	47%
May	0%	0%	44%	0%	0%	0%	0%	0%	0%	49%
June	0%	0%	46%	0%	0%	0%	0%	0%	0%	50%
July	0%	0%	48%	0%	0%	0%	0%	0%	0%	49%
August	0%	0%	48%	0%	0%	0%	0%	0%	0%	49%
September	0%	0%	49%	0%	0%	0%	0%	0%	0%	50%
October	0%	0%	46%	0%	0%	0%	0%	0%	0%	50%
November	0%	0%	43%	0%	0%	0%	0%	0%	0%	49%
December	0%	0%	43%	0%	0%	0%	0%	0%	0%	48%

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #3 **Class Usage @ customer**

Calendar month sales forecasted for 2021, less % for LPL-Sec > 500 kW Peak Load Share

in MWh	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	< 500 kW LPL-S
January	1,158,783	13,581	13,959	83	2	1,504	15,729	32,396	545,910	368,686
February	968,636	11,630	11,729	80	2	1,297	12,919	27,002	502,749	336,398
March	927,889	9,397	11,682	89	1	1,045	12,905	27,387	530,255	357,188
April	768,432	5,786	9,646	74	2	697	10,619	23,671	465,335	311,375
May	921,194	4,420	12,618	94	1	348	10,441	22,013	509,011	370,254
June	1,231,483	5,158	17,644	66	1	470	8,686	18,965	529,954	367,185
July	1,634,450	5,633	23,240	51	1	517	9,402	16,483	608,058	393,837
August	1,648,641	5,820	22,115	58	1	615	10,382	19,112	639,486	424,424
September	1,054,300	4,477	14,454	61	1	432	11,378	23,342	534,120	355,948
October	822,042	4,946	9,887	29	0	470	13,237	25,275	493,454	351,137
November	817,903	7,128	9,473	67	1	656	14,087	24,078	451,146	326,163
December	1,057,091	11,054	12,487	82	1	1,201	15,300	32,133	516,690	359,795
Total	13,010,844	89,030	168,935	834	14	9,253	145,085	291,857	6,326,170	4,322,392

Table #4 **Forwards Prices - Energy Only @ bulk system**

in $/MWh, not including PJM losses

	On-Peak	Off/On Pk LMP ratio	Resulting Off-Peak
January	47.45	0.7621	36.162
February	44.75	0.7621	34.104
March	32.10	0.7621	24.463
April	29.10	0.7621	22.177
May	29.00	0.7621	22.101
June	30.95	0.6706	20.756
July	37.20	0.6706	24.948
August	34.70	0.6706	23.271
September	32.30	0.6706	21.662
October	30.50	0.7621	23.244
November	30.90	0.7621	23.549
December	34.50	0.7621	26.293

Table #5 **Zone to Western Hub Basis Differential**

	On-Peak	Off-Peak	
January	90%	94%	*NYMEX Forwards (June 4, 2021) from NERA*
February	90%	94%	
March	90%	94%	*Congestion Factors & On/Off Peak Ratios*
April	90%	94%	*Summer Averages for June 2018-Sep 2020*
May	90%	94%	*Winter Averages for Mar 2018-Feb 2021*
June	88%	90%	
July	88%	90%	
August	88%	90%	
September	88%	90%	
October	90%	94%	
November	90%	94%	
December	90%	94%	

Table #6 **Losses**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
from meter to bulk system (includes Delivery & PJM EHV losses)										
Loss Factors =	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%	6.2621%
Expansion Factor =	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804	1.066804
1 / Expansion Factor =	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379	0.937379
from meter to transmission node (includes Delivery less mean hourly PJM marginal losses)										
Loss Factors =	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%	5.1535%
Expansion Factor =	1.054335	1.054335	1.054335	1.054335	1.054335	1.054335	1.054335	1.054335	1.054335	1.054335
1 / Expansion Factor =	0.948465	0.948465	0.948465	0.948465	0.948465	0.948465	0.948465	0.948465	0.948465	0.948465

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #7 **Summary of Average BGS Energy Only Unit Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & all losses - PJM time periods
in $/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 27.06	$ 26.96	$ 27.21	$ 26.58	$ 26.75	$ 27.89	$ 23.85	$ 23.71	$ 27.54	$ 27.25
	PJM on pk	$ 31.96	$ 31.77	$ 31.96	$ 31.42	$ 31.63	$ 31.78	$ 31.57	$ 31.40	$ 31.77	$ 31.71
	PJM off pk	$ 22.00	$ 21.86	$ 21.99	$ 21.62	$ 21.76	$ 21.87	$ 21.79	$ 21.66	$ 21.86	$ 21.84
Winter - all hrs		$ 30.49	$ 31.76	$ 30.37	$ 30.23	$ 31.71	$ 32.14	$ 28.88	$ 28.94	$ 30.54	$ 30.31
	PJM on pk	$ 34.11	$ 35.57	$ 33.96	$ 33.84	$ 35.50	$ 35.69	$ 34.51	$ 34.62	$ 33.65	$ 33.53
	PJM off pk	$ 27.02	$ 28.21	$ 26.94	$ 26.78	$ 28.10	$ 28.57	$ 26.71	$ 26.77	$ 26.68	$ 26.57
Annual		$ 29.02	$ 30.62	$ 28.92	$ 29.19	$ 30.29	$ 31.20	$ 27.49	$ 27.54	$ 29.44	$ 29.22
System Total		$ 29.15									

Table #8 **Summary of Average BGS Energy Only Costs @ customer - PJM Time Periods**
based on Forwards prices corrected for congestion & all losses
in $1000

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 150,702	$ 569	$ 2,108	$ 6	$ 0	$ 57	$ 950	$ 1,847	$ 63,660	$ 42,000
	PJM on pk	$ 90,444	$ 345	$ 1,296	$ 4	$ 0	$ 39	$ 265	$ 515	$ 42,090	$ 26,787
	PJM off pk	$ 60,257	$ 224	$ 812	$ 3	$ 0	$ 17	$ 685	$ 1,332	$ 21,571	$ 15,213
Winter - all hrs		$ 226,907	$ 2,158	$ 2,779	$ 18	$ 0	$ 232	$ 3,039	$ 6,191	$ 122,592	$ 84,292
	PJM on pk	$ 124,378	$ 1,165	$ 1,519	$ 10	$ 0	$ 129	$ 1,007	$ 2,045	$ 74,797	$ 50,052
	PJM off pk	$ 102,529	$ 993	$ 1,259	$ 8	$ 0	$ 103	$ 2,032	$ 4,146	$ 47,795	$ 34,240
Annual		$ 377,609	$ 2,726	$ 4,886	$ 24	$ 0	$ 289	$ 3,989	$ 8,039	$ 186,252	$ 126,292
System Total		$ 710,106									

Table #9 **Summary of Average BGS Energy Only Unit Costs @ customer - PSE&G Time Periods**
based on Forwards prices corrected for congestion & all losses - PSE&G billing time periods
in $/MWh

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Summer - all hrs		$ 27.06	$ 26.96	$ 27.21	$ 26.58	$ 26.75	$ 27.89	$ 23.85	$ 23.71	$ 27.54	$ 27.25
	PSE&G On pk			$ 32.44							$ 32.24
	PSE&G Off pk			$ 22.43							$ 22.36
Winter - all hrs		$ 30.49	$ 31.76	$ 30.37	$ 30.23	$ 31.71	$ 32.14	$ 28.88	$ 28.94	$ 30.54	$ 30.31
	PSE&G On pk			$ 34.46							$ 33.94
	PSE&G Off pk			$ 27.31							$ 26.95
Annual Average		$ 29.02	$ 30.62	$ 28.92	$ 29.19	$ 30.29	$ 31.20	$ 27.49	$ 27.54	$ 29.44	$ 29.22
System Average		$ 29.15									

Table #10 **Generation & Transmission Obligations and Costs and Other Adjustments**

Obligations - Peak Load shares eff 1/1/21, scaling factors eff 6/1/21, Transmission Loads eff 1/1/21; costs are market estimates

in MW	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	Adj for PLS > 500 kW LPL-S
Gen Obl - MW	5,161.9	22.5	76.4	0.0	0.0	3.2	0.0	0.0	1,760.2	973.5
Trans Obl - MW	4,459.7	19.4	66.0	0.0	0.0	2.9	0.0	0.0	1,565.6	827.5

\# of Months and Days used in this analysis

# of summer days =	122	# of summer months =	4
# of winter days =	243	# of winter months =	8
		total # months =	12

Transmission Cost — year round = $0.00 per MW-yr

		Base Capacity	
Generation Capacity cost	summer =	$ 104.84	$/MW/day
	winter =	$ 104.84	$/MW/day

	RS	RHS	
<u>% usage in Summer Blocks</u>			
Block 1 (0-600 kWh/m)	64.6%	66.1%	*(based on W/N actuals used in settlement and final rate design of 2018 Rate Case, rounded to .1%)*
Block 2 (>600 kWh/m)	35.4%	33.9%	
Required summer inversion =	0.8652	1.1569 ¢/kWh	*(same as 2003/2004 BGS blocking inversion)*

Table #11 **Ancillary Services & Renewable Power Cost**

Ancillary Services	$ 2.00	
Renewable Power Cost	$ 15.26	
Total AncillaryServices & Renewable Power Costs	$ 17.26	per MWh @ bulk system

Table #12 **Summary of Obligation Costs Expressed as $/MWh @ customer (for non-demand rates only)**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Transmission Obl - all months	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Generation Obl -								
per annual MWh	$ 15.18	$ 9.67	$ 38.35	$ -	$ -	$ 13.23	$ -	$ -
recovery per summer MWh	$ 11.86	$ 13.65	$ 26.40	$ -	$ -	$ 20.12	$ -	$ -
recovery per winter MWh	$ 17.67	$ 8.44	$ 49.62	$ -	$ -	$ 11.29	$ -	$ -
			For RLM, per on-peak kWh only					

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #13 **Summary of BGS Unit Costs @ customer**

NON-DEMAND RATES
includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods
in $/MWh

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs	$ 60.66	$ 55.04		$ 44.99	$ 45.17	$ 59.54	$ 42.26	$ 42.13
PSE&G On pk			$ 89.20					
PSE&G Off pk			$ 40.84					
Block 1 (0-600 kWh/m)	$ 57.59	$ 51.12						
Block 2 (>600 kWh/m)	$ 66.25	$ 62.69						
Winter - all hrs	$ 64.09	$ 59.84		$ 48.64	$ 50.12	$ 63.78	$ 47.29	$ 47.35
PSE&G On pk			$ 91.22					
PSE&G Off pk			$ 45.72					
Annual -all hrs	$ 62.62	$ 58.71	$ 64.64	$ 47.61	$ 48.71	$ 62.85	$ 45.91	$ 45.96

DEMAND RATES
includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods
in $/MWh

	GLP	LPL-S
Summer - all hrs	$ 45.95	$ 45.66
PSE&G On pk		$ 50.65
PSE&G Off pk		$ 40.77
Winter - all hrs	$ 48.95	$ 48.72
PSE&G On pk		$ 52.35
PSE&G Off pk		$ 45.36
Annual - all hrs per MWh only	$ 47.85	$ 47.63
Including Generation Obligation $		
Summer - all hrs	$ 55.67	$ 53.72
PSE&G On pk		$ 66.94
PSE&G Off pk		$ 40.77
Winter - all hrs	$ 60.14	$ 57.65
PSE&G On pk		$ 70.93
PSE&G Off pk		$ 45.36
Annual - including Gen Obl $	$ 58.50	$ 56.25

Note: Obligation $ included in On pk costs

PLUS:	GLP	LPL-S	
Gen Cost			
summer	$ 3.1976	$ 3.1976	per kW of G obl /month
winter	$ 3.1845	$ 3.1845	per kW of G obl /month
annual	$ 3.1889	$ 3.1889	per kW of G obl /month
Trans cost			
all months	$ -	$ -	per kW of T obl /month

ALL RATES

Grand Total Cost in $1000 =	$ 1,464,774	
All-In Average cost @ customer =	$ 60.12	per MWh at customer (per customer metered MWh)
All-In Average costs @ transmission nodes =	$ 57.02	per MWh at transmission nodes (per metered MWh at transmission node)

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #14 **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes -** *rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places*

NON-DEMAND RATES
includes energy, Generation obligations, Ancillary Services and Renewable Power Costs- adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs					**0.789**	**0.792**	**1.044**	0.741	0.739	
	PSE&G On pk			**1.564**				Use weighted average		
	PSE&G Off pk			**0.716**				for all streetlighting =		**0.740**
	All usage Multiplier	**1.064**	**0.965**							
	Constant (in $/MWh)	**$ (3.063)**	**$ (3.922)**	for Block 1 (0-600 kWh/m) usage						
	Constant (in $/MWh)	**$ 5.589**	**$ 7.647**	for Block 2 (>600 kWh/m) usage						
Winter - all hrs		**1.124**	**1.049**		**0.853**	**0.879**	**1.119**	0.829	0.830	
	PSE&G On pk			**1.600**				Use weighted average		
	PSE&G Off pk			**0.802**				for all streetlighting =		**0.830**
Annual - all hrs		1.098	1.030	1.134	0.835	0.854	1.102	0.805	0.806	

DEMAND RATES
includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**0.976**	**(9.713)**		
	PSE&G On pk			**1.174**	**(16.284)**
	PSE&G Off pk			**0.715**	**-**
Winter - all hrs		**1.055**	**(11.185)**		
	PSE&G On pk			**1.244**	**(18.575)**
	PSE&G Off pk			**0.796**	**-**
Annual - including Gen Obl $		1.026		0.986	

PLUS:

<u>Gen Cost</u>			
summer	$ 3.1976	$ 3.1976	per kW of G obl /month
winter	$ 3.1845	$ 3.1845	per kW of G obl /month
annual	$ 3.1889	$ 3.1889	per kW of G obl /month
<u>Trans cost</u>			
all months	$ -	$ -	per kW of T obl /month

Assumptions:

Gen Cost = $ 104.84 /MW day summer
$ 104.84 /MW day winter

Trans cost = $ - per MW-yr
Analysis time period = 4 summer months
8 winter months
Ancillary Services & RPS = $ 17.26 per MWh
Energy Costs = based on Forwards @ PJM West - corrected for congestion
Usage patterns = forecasted 2021 energy use by class, PJM and PSE&G on/off % from 2018, 2019 & 2020 class load profiles

Obligations = class totals in effect as of filing date
Losses = Delivery losses from tariff, PJM losses based on 3 year average %
PJM Time Periods = PJM trading time periods - 7 AM to 11 PM weekdays, local time, x NERC holidays - New Year's, Memorial, 4th of July, Labor Day, Thanksgiving & Christmas
PSE&G Billing time periods = as per specific rate schedule
NJ SUT (Sales & Use Tax) = SUT excluded from all rates

Public Service Electric and Gas Company Specific Addendum
Attachment 2

Table #15 **Summary of Total BGS Costs by Season**

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Costs by Rate - in $1000										
Summer	$ 337,787	$ 1,161	$ 4,953	$ 11	$ 0	$ 121	$ 1,684	$ 3,282	$ 128,738	$ 82,833
Winter	$ 476,919	$ 4,066	$ 5,967	$ 29	$ 1	$ 460	$ 4,977	$ 10,131	$ 241,355	$ 160,299
Total	$ 814,706	$ 5,227	$ 10,920	$ 40	$ 1	$ 582	$ 6,661	$ 13,413	$ 370,093	$ 243,132
% of Annual Total $ by Rate										
Summer	41%	22%	45%	27%	26%	21%	25%	24%	35%	34%
Winter	59%	78%	55%	73%	74%	79%	75%	76%	65%	66%

Total Costs - in $1000	
Summer	$ 560,570
Winter	$ 904,204
Total	$ 1,464,774

rounded to 4 decimal places

		If total $ were split on a per MWh basis (on transmission node MWhs):			
% of Annual Total $					
Summer	38%	$ 55.15 per MWh @ trans nodes	Ratio to All-In Cost >>>	Summer	1.0000
Winter	62%	$ 58.25 per MWh @ trans nodes		Winter	1.0000

Table #16 **Spreadsheet Error Checking -** *Reconciliation of Customer Revenue and Supplier Payments, based on above data only*

Assumed Winning Bid Price =	$ 57.02	*(bid includes payments for all losses)*
Payment Ratio - Summer =	1.0000	
Payment Ratio - Winter =	1.0000	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 337,865	$ 1,160	$ 4,952	$ 11	$ 0	$ 121	$ 1,681	$ 3,287	$ 128,709	$ 82,835
Winter	$ 476,969	$ 4,064	$ 5,968	$ 29	$ 1	$ 461	$ 4,981	$ 10,126	$ 241,445	$ 160,347
Total	$ 814,834	$ 5,224	$ 10,920	$ 40	$ 1	$ 582	$ 6,662	$ 13,413	$ 370,153	$ 243,182

Total Summer	$ 560,622
Total Winter	$ 904,390
Grand Total	$ 1,465,011

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Supplier Payment - in $1000										
Summer	$ 334,797	$ 1,268	$ 4,656	$ 14	$ 0	$ 122	$ 2,396	$ 4,683	$ 138,973	$ 92,668
Winter	$ 447,407	$ 4,085	$ 5,500	$ 36	$ 1	$ 434	$ 6,327	$ 12,863	$ 241,352	$ 167,192
Total	$ 782,204	$ 5,352	$ 10,156	$ 50	$ 1	$ 556	$ 8,722	$ 17,546	$ 380,325	$ 259,860

Total Summer	$ 579,578
Total Winter	$ 885,196
Grand Total	$ 1,464,774

Difference (in $1000) = $ 238

Note: Minor differences in totals are due to rounding of Bid Factors and Payment Factors

Table #17 **Total Supplier Energy** *@ transmission nodes*

in MWh	
Summer	10,164,267
Winter	<u>15,523,987</u>
Total	25,688,254

VII. ATTACHMENT 3 - SPREADSHEETS FOR THE CALCULATION OF BGS RATES

(Pages 1 through 6)

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table A **Auction Results**

line #	**Specific BGS-FP Auction >>**	*remaining portion of 36 month bid - 2020 auction*	*remaining portion of 36 month bid - 2021 auction*	*36 month bid - 2022 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 102.16	$ 64.80	$ 57.48	2022 Illustrative (Excluding transmission)
1A	Capacity Proxy Price True-Up - in $/MWh	$ (7.32)	$ (7.32)	$ -	entered after 2022 Auction
1B	Transmission Price	$ 37.77	$ -	$ -	asssumed transmission price in bids
1C	**Total - in $/MWh**	$ 57.07	$ 57.48	$ 57.48	= line 1 + line 1A - line 1B
	(includes all payments, including impact of PJM marginal losses)				
2	**# of Tranches for Bid**	28	29	28	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	
5	Winter	1.0000	1.0000	1.0000	
	Applicable Customer Usage @ transmission nodes - *in MWh*				
6	Summer MWh	10,164,267			from Table #17 of the current Bid Factor Spreadsheet
7	Winter MWh	15,523,987			
	Total Payment to Suppliers *- in $1000*				
8	Summer	$ 166,574	$ 173,945	$ 192,456	= ((1 - 1B) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 254,411	$ 265,668	$ 293,940	= ((1 - 1B) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 420,985	$ 439,614	$ 486,397	Note: $ reflect total payment
	Average Payment to Suppliers *- in $/MWh*				
11	Summer	$ 52.436			= sum(line 8) / (6) - rounded to 3 decimal places
12	Winter	$ 52.436			= sum(line 9) / (7) - rounded to 3 decimal places
13	Total weighted average	**$ 52.436**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 3 decimal places
	Reconciliation of amounts *- in $1000*				
14	Weighted Average * Total MWh =	$ 1,346,989			= (13) * [(6)+(7)] / 1000
15	Total Payment to Suppliers =	$ 1,346,995			= sum (line 10)
16	Difference =	$ (6)			= line (14) - line (15)

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table B **Ratio of BGS Unit Costs @ customer to All-In Average Cost @ transmission nodes**

from Table #14 of the bid factor spreadsheet ---
rounded to 3 decimal places, unit obligation $ rounded to 4 decimal places

NON-DEMAND RATES

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

		RS		RHS		RLM	WH	WHS	HS	PSAL	BPL	
Summer - all hrs							**0.789**	**0.792**	**1.044**	0.741	0.739	
	PSE&G On pk					**1.564**				Use weighted average		
	PSE&G Off pk					**0.716**				for all streetlighting =		**0.740**
	All usage Multiplier	**1.064**		**0.965**								
	Constant (in $/MWh)	**$ (3.063)**	**$**	**(3.922)**	for Block 1 (0-600 kWh/m) usage							
	Constant (in $/MWh)	**$ 5.589**	**$**	**7.647**	for Block 2 (>600 kWh/m) usage							
Winter - all hrs		**1.124**		**1.049**			**0.853**	**0.879**	**1.119**	0.829	0.830	
	PSE&G On pk					**1.600**				Use weighted average		
	PSE&G Off pk					**0.802**				for all streetlighting =		**0.830**
Annual - all hrs		1.098		1.030		1.134	0.835	0.854	1.102	0.805	0.806	

DEMAND RATES 41.46

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP Multiplier	GLP Constant (in $/MWh)	LPL-S Multiplier	LPL-S Constant (in $/MWh)
Summer - all hrs		**0.976**	**(9.713)**		
	PSE&G On pk			**1.174**	**(16.284)**
	PSE&G Off pk			**0.715**	**-**
Winter - all hrs		**1.055**	**(11.185)**		
	PSE&G On pk			**1.244**	**(18.575)**
	PSE&G Off pk			**0.796**	**-**
Annual - including T&G Obl $		1.026		0.986	

PLUS:		**GLP**	**LPL-S**	
Gen Cost				
	summer	$ 3.1889	$ 3.1889	per kW of G obl /month
	winter	$ 3.1889	$ 3.1889	per kW of G obl /month
Trans cost				
	all months	$ -	$ -	per kW of T obl /month

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table C **Preliminary Resulting BGS Rates (in cents per kWh) -** *equal to bid factors times weighted average bid price rounded to 4 decimal places*

NON-DEMAND RATES --

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***4.1372***	***4.1529***	***5.4743***	***3.8803***	***3.8803***
	PSE&G On pk			***8.2010***					
	PSE&G Off pk			***3.7544***					
for Block 1 (0-600 kWh/m) usage		***5.2729***	***4.6679***						
for Block 2 (>600 kWh/m) usage		***6.1381***	***5.8248***						
Winter - all hrs		***5.8938***	***5.5005***		***4.4728***	***4.6091***	***5.8676***	***4.3522***	***4.3522***
	PSE&G On pk			***8.3898***					
	PSE&G Off pk			***4.2054***					

DEMAND RATES --

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods

		GLP	LPL-S
Summer - all hrs		***4.1465***	
	PSE&G On pk		***4.5276***
	PSE&G Off pk		***3.7492***
Winter - all hrs		***4.4135***	
	PSE&G On pk		***4.6655***
	PSE&G Off pk		***4.1739***

PLUS:		GLP		LPL-S	
Gen Cost					
summer	**$**	**3.1889**	**$**	**3.1889**	per kW of G obl /month
winter	**$**	**3.1889**	**$**	**3.1889**	per kW of G obl /month
Trans cost					
all months	**$**	**-**	**$**	**-**	per kW of T obl /month

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table D **Revenue Recovery Calculations -** *Reconciliation of seasonal Customer Revenue and Supplier Payments, based on actual anticipated revenues and payments*

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Total Preliminary Rate Revenue - in $1000								
Summer	$ 310,698	$ 1,067	$ 4,554	$ 10	$ 0	$ 111	$ 1,546	$ 3,023
Winter	$ 438,615	$ 3,737	$ 5,488	$ 27	$ 0	$ 424	$ 4,580	$ 9,312
Total	$ 749,312	$ 4,804	$ 10,042	$ 37	$ 1	$ 535	$ 6,126	$ 12,335

	GLP Energy $	GLP Obligation $	LPL-S Energy $	LPL-S Obligation $
Summer	$ 95,851	$ 22,452	$ 63,726	$ 12,418
Winter	$ 177,182	$ 44,905	$ 122,649	$ 24,835
Total	$ 273,033	$ 67,357	$ 186,375	$ 37,253

	Energy $	Obligation $	Total $
Total Summer	$ 480,586	$ 34,870	$ 515,456
Total Winter	$ 762,014	$ 69,740	$ 831,754
Grand Total	$ 1,242,600	$ 104,610	**$ 1,347,210**

Total Supplier Payment - in $1000	
Summer	$ 532,976
Winter	$ 814,019
Total	$ 1,346,995
Differences - in $1000	
Summer	$ 17,520
Winter	$ (17,735)
Total	$ (214)

kWh Rate Adjustment Factors	*rounded to 5 decimal places*
1.03646	
0.97673	

Note: These differences are due to rounding and seasonal differences in Bidder Payments (which are based on prior wining bids and Seasonal Payment Factors) and current Rates (based on current seasonal market differentials)

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table E **Final Resulting BGS Rates from Auctions (in cents per kWh) -** *with preliminary kWh rates adjusted by the kWh Rate Adjustment Factor rounded to 4 decimal places*

NON-DEMAND RATES --

includes energy, G&T obligations, and Ancillary Services - adjusted to billing time periods & adjustment to energy price

		RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Summer - all hrs					***4.2880***	***4.3043***	***5.6739***	***4.0218***	***4.0218***
	PSE&G On pk			***8.5000***					
	PSE&G Off pk			***3.8913***					
for Block 1 (0-600 kWh/m) usage		***5.4651***	***4.8381***						
for Block 2 (>600 kWh/m) usage		***6.3619***	***6.0372***						
Winter - all hrs		***5.7567***	***5.3725***		***4.3687***	***4.5018***	***5.7311***	***4.2509***	***4.2509***
	PSE&G On pk			***8.1946***					
	PSE&G Off pk			***4.1075***					

DEMAND RATES --

includes energy and Ancillary Services, G&T obligations charged separately - adjusted to billing time periods & adjustment to energy price

		GLP	LPL-S
Summer - all hrs		***4.2977***	
	PSE&G On pk		***4.6927***
	PSE&G Off pk		***3.8859***
Winter - all hrs		***4.3108***	
	PSE&G On pk		***4.5569***
	PSE&G Off pk		***4.0768***

PLUS:		**GLP**	**LPL-S**
Gen Cost			
	summer	**$3.1889**	**$3.1889**
	winter	**$3.1889**	**$3.1889**
Trans cost			
	all months	**$0.0000**	**$0.0000**

Calculation of June 2022 to May 2023 BGS-RSCP Rates

Illustrative Only

NJ Sales & Use Tax (SUT) excluded

Table F **Spreadsheet Error Checking** - *Checking of seasonal Customer Revenue and Supplier Payments, based on final actual anticipated revenues and payments*

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	GLP	LPL-S
Total Rate Revenue - in $1000										
Summer	$ 322,024	$ 1,106	$ 4,720	$ 10	$ 0	$ 115	$ 1,603	$ 3,133	$ 121,799	$ 78,467
Winter	$ 428,412	$ 3,650	$ 5,361	$ 26	$ 0	$ 414	$ 4,474	$ 9,095	$ 217,964	$ 144,630
Total	$ 750,436	$ 4,756	$ 10,080	$ 36	$ 1	$ 529	$ 6,076	$ 12,228	$ 339,763	$ 223,097

Total Summer	$ 532,977	
Total Winter	$ 814,026	
Grand Total	$ 1,347,002	
Total Supplier Payment - in $1000		
Summer	$ 532,976	
Winter	$ 814,019	
Total	$ 1,346,995	
Differences - in $1000		% difference
Summer	$ 1	0.0002%
Winter	$ 6	0.0008%
Total	$ 7	0.0005%

VIII. ATTACHMENT 4 – DEVELOPMENT OF CAPACITY PROXY PRICE TRUE UP - $/MWh

(Pages 1 through 5)

Development of Capacity Proxy Price True-Up - $/MWh
2022/2023 Delivery Year - Illustrative Data

		2022/23 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$97.75	as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$162.13	per Board Orders dated 11/13/2019 and 11/18/2020
3	**Capacity Proxy Price True-Up - $/MW-day**	-$64.38	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	7,997.7	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	-$187,935,553	= line 3 * line 4 * line 5
7	**Eligible Tranches**	57	from Table A
8	**Total Tranches**	85	from Table A
9	**% of tranches eligible for payment**	67.06%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	-$126,027,371	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	25,688,254	
12	**Eligible Customer Usage @ bulk system - *in MWh***	17,226,241	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**-$7.32**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh

2023/2024 Delivery Year - Illustrative Data	Capacity Proxy Price True-Up Development for Winning Suppliers from 2021 BGS-RSCP Auction 2023/24 Delivery Year	Capacity Proxy Price True-Up Development for Winning Suppliers from 2022 BGS-RSCP Auction 2023/24 Delivery Year	*Notes:*
1 **Zonal Capacity Price ($/MW-day)**	$170.00	$170.00	as may be determined by the RPM or its successor or otherwise
2 **Capacity Proxy Price ($/MW-day)**	$166.64	$128.79	per Board Orders dated 11/18/2020 and XX/XX/2021
3 **Capacity Proxy Price True-Up - $/MW-day**	$3.36	$41.21	= line 1 - line 2
4 **BGS-RSCP Gen Obl - MW**	7,997.7	7,997.7	
5 **Days in Year**	365	365	
6 **Capacity Proxy Price True-Up Annual Cost**	$9,808,379	$120,298,604	= line 3 * line 4 * line 5
7 **Eligible Tranches**	29	28	from Table A
8 **Total Tranches**	85	85	from Table A
9 **% of tranches eligible for payment**	34.12%	32.94%	= line 7 / line 8
10 **Capacity Proxy Price True-Up Cost**	$3,346,388	$39,627,776	= line 6 * line 9
11 **Total Applicable Customer Usage @ bulk system - in MWh**	25,688,254	25,688,254	
12 **Eligible Customer Usage @ bulk system - *in MWh***	8,764,228	8,462,013	= line 9 * line 11
13 **Capacity Proxy Price True-Up - $/MWh**	**$0.38**	**$4.68**	**= line 10/ line 12 - rounded to 2 decimal places**

Development of Capacity Proxy Price True-Up - $/MWh
2024/2025 Delivery Year - Illustrative Data

		2024/25 Delivery Year	*Notes:*
1	**Zonal Capacity Price ($/MW-day)**	$90.00	as may be determined by the RPM or its successor or otherwise
2	**Capacity Proxy Price ($/MW-day)**	$87.98	per Board Orders dated xx/xx/2021
3	**Capacity Proxy Price True-Up - $/MW-day**	$2.02	= line 1 - line 2
4	**BGS-RSCP Gen Obl - MW**	7,997.7	
5	**Days in Year**	365	
6	**Capacity Proxy Price True-Up Annual Cost**	$5,896,704	= line 3 * line 4 * line 5
7	**Eligible Tranches**	29	from Table A
8	**Total Tranches**	85	from Table A
9	**% of tranches eligible for payment**	34.12%	= line 7 / line 8
10	**Capacity Proxy Price True-Up Cost**	$2,011,817	= line 6 * line 9
11	**Total Applicable Customer Usage @ bulk system - in MWh**	25,688,254	
12	**Eligible Customer Usage @ bulk system - *in MWh***	8,764,228	= line 9 * line 11
13	**Capacity Proxy Price True-Up - $/MWh**	**$0.23**	**= line 10/ line 12 - rounded to 2 decimal places**

Table A With Additional Line Item

Calculation of June 2023 to May 2024 BGS-RSCP Rates

Illustrative Purposes Only

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2021 auction*	*remaining portion of 36 month bid - 2022 auction*	*36 month bid - 2023 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 57.48	$ 57.48	$ 57.48	winning Bids
1A	**23/24 Capacity Proxy Price True-up - in $/MWh**	$ 0.38	$ 4.68		entered after 2023 BGS Auction
1B	**Total - in $/MWh**	$ 57.86	$ 62.16	$ 57.48	= line 1 + line 1A
2	**# of Tranches for Bid**	29	28	28	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	10,164,267			from current Bid Factor Spreadsheet
7	Winter MWh	15,523,987			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 200,647	$ 208,126	$ 192,456	= ((1) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 306,451	$ 317,873	$ 293,940	= ((1) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 507,098	$ 525,999	$ 486,397	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 59.15			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 59.15			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 59.15**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

Table A With Additional Line Item

Calculation of June 2024 to May 2025 BGS-RSCP Rates

Illustrative Purposes Only

Table A **Auction Results**

line #	**Specific BGS-RSCP Auction >>**	*remaining portion of 36 month bid - 2022 auction*	*remaining portion of 36 month bid - 2023 auction*	*36 month bid - 2024 auction*	*Notes:*
1	**Winning Bid - in $/MWh**	$ 57.48	$ 57.48	$ 57.48	winning Bids
1A	**22/23 Capacity Proxy Price True-up - in $/MWh**	$ 0.23			entered after 2024 BGS Auction
1B	**Total - in $/MWh**	$ 57.71	$ 57.48	$ 57.48	= line 1 + line 1A
2	**# of Tranches for Bid**	28	28	29	from then current Bid
3	**Total # of Tranches**	85	85	85	from then current Bid
	Payment Factors				
4	Summer	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
5	Winter	1.0000	1.0000	1.0000	from then current Bid Factor Spreadsheet
	Applicable Customer Usage @ bulk system - in MWh				
6	Summer MWh	10,164,267			from current Bid Factor Spreadsheet
7	Winter MWh	15,523,987			
	Total Payment to Suppliers - *in $1000*				
8	Summer	$ 193,226	$ 192,456	$ 199,330	= ((1 - 1B) * (2)/(3) * (4) * (6)) + ((1A) * (2)/(3) * (6))
9	Winter	$ 295,116	$ 293,940	$ 304,438	= ((1 - 1B) * (2)/(3) * (5) * (7)) + ((1A) * (2)/(3) * (7))
10	Total	$ 488,343	$ 486,397	$ 503,768	
	Average Payment to Suppliers - *in $/MWh*				
11	Summer	$ 57.56			= sum(line 8) / (6) - rounded to 2 decimal places
12	Winter	$ 57.56			= sum(line 9) / (7) - rounded to 2 decimal places
13	Total weighted average	**$ 57.56**	<<< used in calculation of Customer Rates		= sum(line 10) / [(6) + (7)] rounded to 2 decimal places

VIX. ATTACHMENT 5 – DEVELOPMENT OF ASSUMED TRANSMISSION PRICE IN BIDS-$/MWh

Development of Assumed Transmission Price in Bids
Calculation for 2020/2021

line #		*remaining portion of 36 month bid - 2020 auction*	*Notes:*
1	**Eligible Tranches**	28	
2	**Total Tranches**	85	
3	**Tranche %**	32.94%	= line 1 / line 2
4	**Transmission Obligations (MW)**	6901.0	Obligations from filing years
5	**Adjustment Transmission Obligation (MW)**	2273.3	= line 3 * line 4
6	**NITS Rate ($/MW-yr)**	$ 138,497.08	NITS Rates from from 2020
7	**Payment ($/yr)**	$ 314,841,348	= line 5 * line 6
8	**Pre Loss Usage (MWh)**	25,302,921	Applicable usage from filing year
9	**Allocated Usage (MWh)**	8,335,080	= line 3 * line 8
10	**Transmission Price ($/MWh)**	**$ 37.77**	= line 7 / line 9 (To Attachment 3, Table A, Line 1B)